The Governor's Conference on Local Renewable Energy Resources

California's Path To Local Renewables

Cost and Transparency Panel
Discussion Paper

ISSUE OVERVIEW

The success of the governor's distributed generation goals will depend in critical part on providing adequate financial incentives to developers while keeping overall system costs reasonable. It also will require that developers have adequate data about market mechanisms and utility distribution networks.

This paper discusses issues relating to each of these two objectives. Specifically, it addresses issues relating to (1) procurement tools, and system and developer costs, and (2) achieving transparency in distribution networks and the contracting/bidding processes.

BACKGROUND

At the outset, it is important to put the issue of cost into a broader context. It typically has been assumed that increasing the State's share of renewable energy, and distributed generation in particular, will increase electricity costs substantially. But it is less and less clear that this will occur, or that if there are higher costs from shifting to distributed renewables, that they will be significant. Solar photovoltaic (PV) costs have been rapidly declining over the past several years; the Department of Energy predicts that costs will decline by 50% from 2010 to 2020, and some developers are more optimistic, predicting grid parity by 2015 or even earlier.

At the same time, natural gas costs are predicted to increase by 20-30% over the next decade. Some experts also argue that the cost differentials between solar PV and conventional natural gas plants have been overestimated, particularly once all the benefits of distributed solar PV are included, including the time of use (solar is provided at peak demand periods when the cost of power is at its highest), avoided transmission losses, relieving load on the local distribution substation and transmission lines, and the merit order effect of renewables. (The "merit order" refers to the fact that the price of wholesale electricity is determined by the generation source with the highest cost that successfully bids into the market in a given hour.) Solar PV displaces the need for the highest cost peaking power plants to be run during peak power periods, thereby lowering the cost of all electricity sold into the market during those periods.

The German government estimates that the reduction in electricity prices attributable to increased renewable energy was roughly $5 billion in 2009. This estimated price savings resulting from renewables in California has not yet been calculated, and may be quite substantial (the same benefit would result from larger scale renewable development as well as distributed generation).

Another threshold question is how decisionmakers should balance cost considerations with the numerous environmental, economic, social and energy benefits that result from distributed generation (see Discussion Paper #). For example, to what degree should issues of project quality, equity, and job creation factor into program design? Likewise, what is the balance that should be struck between promoting lower cost systems and having a more diverse, localized portfolio of distributed generation projects? Developing a large number of smaller systems (~<3MW) interconnected on the distribution side of the system would lead to a more geographically diverse portfolio, with more participating owners, that could be brought on line more quickly. On the other hand, such systems may be more expensive than larger projects closer to 20 MW in size, developed in more isolated areas of the State where land costs are cheaper. These are value judgments that need to be explored as the Governor's plan is further developed.

DISCUSSION

A. *Procurement and Cost Issues*

1. *What procurement tools should be used?*

One fundamental question for policymakers is what set of tools to use to stimulate production of distributed generation. The traditional competitive solicitation process used for procurement of large scale renewable projects generally does not work well for smaller scale producers because of the significant transaction costs involved. Nonetheless, each Investor Owned Utility (IOU) is currently implementing its own solar PV program in which half of the projects are secured through a competitive solicitation process (the other half will be owned by the utilities). The three IOU solar programs total 547 megawatts.

The two primary other mechanisms being used in California are a Feed-in-Tariff (FIT) and Reverse Auction Mechanism (RAM). The State has had a FIT for renewables up to 1.5 megawatts in place for several years, but the price has been set too low to stimulate any significant production. The PUC and large publicly owned utilities currently are implementing another FIT for projects up to 3 megawatts with a program cap of 750 megawatts (the PUC's tariff is scheduled to be released in early 2012). Supporters of FITs point to the successful example of Germany, where a FIT led to the development of between 11,000 and 12,000 MW of distributed solar PV in 2009 and 2010, with apparently modest impacts on the cost of electricity. The FIT in Germany (and Spain) is set at a level that includes incentives in addition to the costs of generation. California's FIT law stops short of providing for this but specifies that the tariff can consider the environmental attributes of the technology and other avoided costs associated with the generation and transmission of conventional electricity.

The PUC also has authorized a RAM for projects up to 20 megawatts, with a program cap of 1,000 megawatts, over a two year period. The IOUs are required to hold two auctions per year; bids are selected based on price, and standard, non-negotiable contracts are used. Southern California Edison also initiated a voluntary RAM program of 250 megawatts, which was fully subscribed within a brief period earlier this year. The RAM currently does not extend to publicly owned utilities or electricity service providers.

Proponents of the RAM argue that the market for distributed generation is rapidly evolving and that given the pace of market transformation, efforts to administratively set prices through a FIT will inevitably lag behind changes in the market. FITs thus have the potential to provide windfalls to producers. Spain is offered as a cautionary tale of a FIT program with overly generous payments that generated excess production and windfall profits to producers (at least when the FIT is not coupled with a dynamic scheme for adjusting the level of payments). Reliance on regular competitive auctions, by contrast, will allow consumers to realize reductions in costs through lower prices.

Critics of the RAM counter that the auction mechanism leads to underbidding by developers with the resulting likelihood that many projects will not actually be built. They also contend that because the process is not sufficiently transparent, it creates the possibility of gaming the auction process and that uncertainty about the actual price limits the ability of non-energy companies to make commitments to adding solar PV to multiple facilities. Also, FITs can be adjusted; the German government, for example, adjusts pricing levels as frequently as every six months in response to changes in the market and the level of production. Finally, critics say that the RAM may lead to a large number of projects being selected in the lowest cost, highest insolation areas of the State, even though these areas are distant from load centers and the projects may not be able to interconnect quickly to the grid. (One potential way to address this would be to cluster projects into different groups and allow similar projects to compete on price (either by geographic location, position in the California Independent System Operator

ISO queue, or other criteria).)

On the customer side of the meter, California's incentive programs, particularly the California Solar Initiative (CSI) and Net Energy Metering (NEM) are more mature and generally operating well; the State seems likely to meet its CSI goal of installing 3,000 megawatts of rooftop solar by 2017. There is significant sentiment to expand the current limit on the size of eligible facilities beyond 1 megawatt, as well as the overall system-wide cap for NEM (which is 5% of each utility's peak load demand). Utilities and consumer advocates contend, however, that by allowing customers to receive bill credit at the full retail rate for electricity, the NEM program is unfairly imposing system-wide distribution, transmission and public purpose costs on other ratepayers, and that this should be adjusted in any expansion of the program.

2. *How Can Ratepayers Capture the Benefits of Distributed Generation?*

Another cost-related issue is how to ensure that ratepayers realize the benefits of transmission and distribution investments that will be avoided or deferred because of distributed generation projects. To maximize these benefits, utilities should be required to evaluate their capacity expansion plans and identify the project sites with the highest value for offsetting transmission and distribution upgrades. The FIT, RAM, and other contracting tools should include incentives for developers to locate their projects in these areas. Consumer advocates have additionally suggested that utilities should be precluded from making systems upgrades if the distributed resources are installed in the locations identified in the utilities plans as best suited for distributed generation development.

3. *How can project costs be minimized?*

Beyond the choice of procurement mechanism discussed above, the costs of distributed generation will be influenced by numerous factors, many discussed in other issue papers. How quickly can projects come on line? (presumably quite a bit more quickly than large scale projects, although observers note that smaller project sizes means that there are significantly more projects that have to navigate the permitting, siting and interconnection processes). Can the interconnection process for distributed generation be streamlined? Can the regulatory/permitting processes be streamlined to allow for quicker environmental review, especially for projects with minimal environmental footprint, such as PV panels on rooftops, in parking lots, and/or brownfields and contaminated lands? Can projects be directed to beneficial grid locations where the costs of upgrades are lower? Will low-cost, predictable project financing be available? Will the federal investment tax credits and accelerated depreciation allowance that expires by 2016 continue to be available?

4. *Is an overall cost containment mechanism appropriate?*

Some stakeholders have questioned whether the governor's distributed generation goal should contain an overall cost cap. Such a cap seems premature, given that system costs hopefully will be limited by technology advances, permitting reforms, market-based tools like the RAM and other factors discussed above. Moreover, the State's 33% RPS law already sets an overall cap on renewable procurement costs for each IOU (once the cap is reached, utilities are not obligated to meet the 33% mandate unless they can purchase renewables without causing a "de minimis increase" in rates). If a cost containment measure is deemed appropriate at some future point, though, the "total portfolio" approach of the current RPS law—setting a cap for each IOU – seems more flexible and better suited to accommodate a range of program goals, as compared to placing limits on individual distributed generation contracts.

B. *Transparency Issues*

1. *Transparency in Distribution Systems*

Developers have repeatedly said that they need better information about the "easy" places to interconnect, and other distribution-level data. Indeed, information about locations that are most suitable for distributed generation interconnection, individual distribution circuits that can handle additional distributed generation capacity without incurring major upgrade costs, etc, would help developers locate, size, and develop projects that avoid expensive interconnection and other challenges. The utilities have this data, and could provide it to developers at no cost. Some stakeholders argue that utilities should be proactively planning for locations where distributed PV will have the most beneficial impact, upgrade distribution substations in these areas, and direct PV development to these sites.

2. Market Transparency

Developers argue that disclosure about the biding and selection process used in a RAM or other competitive solicitation process can provide valuable price information to them, and reduce market transaction costs. On the other hand, making this information public raises the potential for gaming the system.

A reasonable middle ground, at least for the RAM, would be to keep information about individual bids confidential, but make transparent market clearing prices and quantities procured as a result of the bidding process. This information would level the playing field for bidders in subsequent auctions. One advantage of a FIT, by contrast, is that the price is fixed and always transparent.

In the context of a competitive solicitation process, some contend that while bid ranking methodologies should be explained, the actual models should not be disclosed in order to avoid attempts to game the process. Others counter that the bid methodologies should be disclosed because the 'least cost best fit' criteria used in awarding contracts can be somewhat subjective and does not give developers enough guidance about what projects, sites, and technologies to bid.

FUTURE QUESTIONS & CHALLENGES

1. The two new contracting mechanisms for medium scale distributed generation, the RAM and FIT, are just being implemented, along with the IOU's Solar PV program. Do we need to design new tools, or should we wait and see how well these work? How will we evaluate their success?

2. Do we have adequate data about what the true costs and benefits of distributed generation as compared to the alternatives will be? The PUC prepared a study in 2009 about the costs of implementing a 33% RPS, but that study has been widely criticized on numerous grounds (including failing to consider any price reductions over time), is now outdated given the rapid reductions in the costs of solar PV that have taken place since then, and evaluated a high distribution generation option only as a sensitivity case. Related, can we calculate the likely depression in wholesale market prices due to additional distributed generation on the grid?

3. What other market and distribution system data do developers need to succeed in the marketplace?